Issues Paper

Review of the application guidelines for the regulatory investment tests

February 2018

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Request for submissions

The Australian Energy Regulator (AER) invites stakeholders to review the matters raised in this issues paper and provide written submissions. We also welcome submissions on relevant issues not discussed in the paper.

We invite submissions by the close of business **6 April 2018**. We prefer stakeholders send submissions electronically to: RIT@aer.gov.au.

Alternatively, stakeholders can mail submissions to:

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We prefer all submissions be publicly available to facilitate an informed and transparent consultation process. We will therefore treat submissions as public documents unless otherwise requested.

We request parties wishing to submit confidential information to:

- clearly identify the information that is subject of the confidentiality claim
- provide a non-confidential version of the submission, in addition to a confidential one.

We will place all non-confidential submissions on our website at www.aer.gov.au. For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy*, June 2014 available on our website.

Please direct enquiries about this paper to RIT@aer.gov.au or to Lisa Beckmann on (02) 6243 1379.

Shortened forms

Shortened Form	Extended Form
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	annual planning report
COAG EC	Council of Australian Governments Energy Council
CCP	Consumer Challenge Panel
DAPR	distribution annual planning report
distribution business	distribution network service provider
Finkel Review	The Commonwealth of Australia's independent review into the future security of the National Electricity Market
the Guarantee	National Energy Guarantee
ISP	Integrated System Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
network business	network service provider — either a distribution or transmission network service provider
preferred option	as defined in NER clause 5.16.1(b) and 5.17.1(b)
repex	replacement expenditure
repex rule change	the replacement expenditure planning arrangements rule change
REZ	Renewable Energy Zones
the RIT application guidelines	collectively, the application guidelines accompanying the regulatory investment test for distribution and

	transmission
RIT–D	regulatory investment test for distribution
RIT proponent	either a RIT–T proponent or a RIT–D proponent, as defined in chapter 5 of the NER
the RITs	collectively, the regulatory investment test for distribution and transmission
RIT–T	regulatory investment test for transmission
TAPR	transmission annual planning report
transmission business	transmission network service provider
VCR	value of customer reliability

Contents

1 Introduction

The Australian Energy Regulator (AER) is reviewing the application guidelines accompanying the regulatory investment tests for transmission (RIT–T) and distribution (RIT–D) (the RIT application guidelines). This is a large-scale review of the RIT application guidelines, consistent with recommendations from the Council of Australian Governments Energy Council (COAG EC) during its RIT–T review.

This issues paper forms an important part of this review by providing stakeholders with the opportunity to provide informed and targeted input. The issues paper provides:

- Information on the current RIT–T and RIT–D (collectively, the RITs) and their separate application guidelines, as well as the context for this review.
- An indication of our initial views on the effectiveness and limitations of the current RIT application guidelines, along with prompting questions to encourage input.
- Information on issues concerning the RITs that others have raised with us and that we wish to explore further, along with prompting questions to encourage input.

1.1 What are the RITs?

The RITs are cost–benefit analysis frameworks that transmission and distribution network service providers (collectively, network businesses) must perform and consult on before making major investments in their networks to address an identified need. When undertaking RITs, network businesses must give due consideration to what options are out there, before identifying the best way to address needs on their networks – which the National Electricity Rules (NER) calls the 'preferred option'. The preferred option is the credible investment option which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the relevant market.[1]

1.2 The AER's role

Among other roles, we are responsible for the economic regulation of electricity transmission and distribution services in the national electricity market (NEM). We are also responsible for ensuring compliance with and enforcement of the NER. As part of these responsibilities, we develop the RITs and have a compliance and monitoring role over the operation and application of the RITs. This includes:[2]

- Developing, publishing and amending the RITs and the RIT application guidelines.
- Determining whether other classes of market benefits or costs proposed by RIT proponents are relevant under the RITs.

1 Where, the relevant market is the NEM in clause 5.17.1(b), but in clause 5.16.1(b), is the 'market' as defined in chapter 10 as 'any of the markets or exchanges described in the Rules, for so long as the market or exchange is conducted by AEMO'. .

2 See NER clauses 5.15–17.

- Determining if a person is an interested party for the purposes of following a RIT consultation process.
- Reviewing the cost thresholds for applying the RITs.
- Allowing network businesses extensions for publishing decisions under the RITs, as well as exemptions from reapplying the RITs following material changes in circumstances.
- Making determinations to settle RIT disputes. We can require a RIT proponent to amend its project assessment conclusions report if the RIT proponent makes errors set out under NER clauses 5.16.5(g) and 5.17.5(g).
- Monitoring the application of the RITs, during and after different stages of the RIT process.

These responsibilities assist in the more transparent and consistent application of the RITs.

1.3 The review process

This process will be a large-scale review of the RIT application guidelines, consistent with recommendations from the COAG EC during its RIT–T review. This process is not intended to consider the appropriateness, effectiveness and efficiency of the test. This was considered by COAG EC in early 2017.

During this process, we will carefully consider and consult on issues that have arisen through the application of the RITs and the use of the current RIT application guidelines. These include:

- Specific issues identified in the COAG EC's review of the RIT–T, finalised in February 2017.[3]
- Any remaining issues arising from the replacement expenditure (repex) planning arrangements rule change (repex rule change), finalised in July 2017.[4]
- Any issues identified as part of our regular compliance monitoring of the RITs undertaken by network businesses, and other provisions in the RIT application guidelines that require amendment;
- Any other issues or potential improvements that stakeholders identify throughout this consultation process.

Table 1 summarises the main project steps and proposed dates for this consultation process.

Table 1: Indicative project timeline

Project step	Expected date
Review commences	15 December 2017

3 COAG EC, *RIT–T review*, February 2017.

4 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017.

Issues paper	20 February 2018
Stakeholder workshop	March 2018
Submissions close on issues paper	6 April 2018
Draft amendments to application guidelines	May/June 2018
Stakeholder workshop	June 2018
Submissions close on draft amendments	July/September 2018
Final amendments to application guidelines	September/October 2018

1.4 Summary of questions

This issues paper forms an important part of our consultation process. To help encourage input, we have included questions, along with some of our initial views, throughout this paper. For convenience, we have also included these questions below.

Table 2: Summary of questions with section references

Question	Section reference
Question 1: Do you agree that the RITs promote the long-term interests of consumers by promoting competitive neutrality and investment efficiency? Are there any other factors we should consider?	3. The role of the RITs in promoting the long term interest of consumers
Question 2: Do you agree that a RIT assessment is not required where the external financial contribution results in the project falling below the cost threshold?	4.1. When do the RITs apply?
Question 3: How do you think we should amend the RIT application guidelines to better facilitate consumer engagement throughout the RIT application process?	4.2. Consumer engagement and the RITs
Question 4: What specific guidance would help distribution businesses better use their non-network options reports and non-network screening requirements to engage with non-network service providers? Are there specific ways we should complement this guidance with greater oversight over distribution business' non-network engagement activities?	4.3. Screening for non-network options
Question 5: Do you agree that the RIT–T process accommodates the consultation required for proponents to effectively test the market, but would benefit from guidance to better align information provided in the project specification consultation report with that provided in the non-network options report under the RIT–D? Alternatively, would it be preferable to request a rule change for non-network consultation under the RIT–T to more closely mirror what the NER require for the RIT–D?	4.4. Scope for more consistency between the RITs
Question 6: What additional guidance should the RIT application guidelines provide regarding the information network businesses should	4.5. Cancellation of

publish when they cancel RIT assessments?	RIT assessments
Question 7: Do you agree with our proposed approach of providing further guidance on how RIT proponents should describe an identified need?	5.1. Identified need
Question 8: Is there any specific guidance you would like us to provide in clarifying how RIT proponents should calculate option value, make forecasts and test different states of the world? Are there particular scenarios where a worked example would be helpful in providing this guidance?	5.2. Option value and scenario analysis
Question 9: Would any guidance in addition to the areas listed in section 5.3 of this issues paper assist in the application of the RITs to repex projects? Is there particular guidance stakeholders would like to help understand how the RITs will apply to asset replacement programs?	5.3. Replacement expenditure
Question 10: Do you agree that the RIT is a market-wide cost–benefit analysis? Do you agree that, as a consequence of this, funds that move between parties within the market should not affect the final net-benefit, but funds that comes from outside the market to a party within the market should increase the final net benefit?	5.4. Accounting for external funds when applying RITs
Question 11: Do you agree that the scenario analysis currently prescribed in the RIT application guidelines can sufficiently capture the effects of high impact, low probability events and system security requirements? Do the RIT–T application guidelines require expanding to assist proponents in accounting for these events? Is there specific guidance you would like on this topic, or particular scenarios where a worked example would be helpful—and how (if at all) should this differ between the RIT–D and RIT–T application guidelines?	5.5. Treatment of high impact, low probability events
Question 12: What additional guidance would stakeholders find useful in regarding the treatment of environmental policies in the RIT–T application guidelines?	5.6. Environmental policy and the National Energy Guarantee
Question 13: Do you support our proposal to expand our RIT application guidelines to specify that, as a default, RIT proponents should use the same discount rate when comparing different credible options?	5.7. Discount rate and treatment of risks
Question 14: What kind of additional guidance, if any, would you like the RIT application guidelines to provide on selecting an appropriate VCR?	5.8. Value of customer reliability
Question 15: Should we revise the RIT–D application guidelines to clarify that a 'business-as-usual' base case should be used for repex projects? Is there any other guidance the RIT application guidelines should provide on selecting an appropriate base case?	5.9. Selection of base case
Question 16: Given AEMO is currently developing the Integrated System Plan (ISP), what additional guidance would stakeholders find useful in the RIT–T application guidelines with respect to the ISP?	6. Other RIT issues — Integrated System Plan

While this issues paper asks these questions, we would welcome input on any issues stakeholders consider important to improve the operation of the RIT application guidelines.

2 Background

This section includes background information to assist stakeholders in understanding the current role of the RIT application guidelines in the operation of the RITs. It provides context around this review of the RIT application guidelines. It also explains projects and ongoing work that will have interrelationships with this review.

2.1 Current RIT application guidelines

We published the application guidelines in June 2010 for the RIT–T and August 2013 for the RIT–D. We made minor amendments to both RIT application guidelines in September 2017 to incorporate changes necessary to accommodate the repex rule change.

Each of the RIT application guidelines provide guidance on:[5]

- The purpose of RITs and projects subject to assessment.
- How an identified need should be expressed and what constitutes an identified need, for the purposes of RIT assessments.
- Identifying reasonable scenarios for differing 'states of the world' to use in conducting a sensitivity analysis as part of the cost–benefit analysis.
- Identifying credible options, including the number and range of credible options. This explains how these options must address the identified need and be commercially and technically feasible.
- How to select a preferred option — that is, the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the relevant market.
- Valuing costs, including the costs of complying with laws and regulations.
- How to value market benefits by deriving relevant states of the world, comparing these states and weighting benefits in each reasonable scenario. The RIT application guidelines also explain the different classes or categories of market benefits.
- The treatment of uncertainty and risk, including around market benefits and costs. This includes guidance on how an appropriate formulation of credible options and an appropriate selection of reasonable scenarios can enable the assessment to capture option values.
- The externalities which should not be included in the RIT assessments — for example, impacts on parties other than in their capacity as producers, consumers or transporters of electricity — in either the costs or benefits of credible options.
- How to pick a suitable modelling period for the RITs.

5 AER, *RIT–T application guidelines*, September 2017; AER, *RIT–D application guidelines*, September 2017.

- The process to follow in applying the RITs by describing the stakeholder consultation steps prescribed in the NER, as well as the process for reapplying a RIT following a material change in circumstances.
- The dispute resolution process. This includes guidance on the requirements and procedure for making a RIT dispute, along with how we will make a determination on the dispute.
- Calculating different classes of market benefits, using worked examples. This includes benefits associated with voluntary load curtailment, involuntary load shedding, costs to other parties, timing of expenditure, option value and energy/network losses.

The nature and level of guidance differs between the RIT–T and RIT–D application guidelines. Only the RIT–D application guidelines provide specific guidance on:

- The treatment of land under 'valuing costs', clarifying that the market value of land should be included as part of the RIT–D assessment. We included guidance on this cost category in the RIT–D application guidelines in response to stakeholder feedback during the RIT–D consultation process in 2013.[6] In our view, similar guidance could potentially be applied to the RIT–T.
- Determining what constitutes a material and adverse NEM impact,[7] which is required to understand who is an 'interested party' with whom RIT proponents must consult.[8] In our view, similar guidance could potentially be applied to the RIT–T.
- Selecting the appropriate discount rate. This aligns with how the discount rate is selected in the RIT–T, which is set in the RIT–T itself as opposed to its application guidelines.[9]
- Screening for non-network options before publishing a determination and an exemption from publishing a non-network options report.[10] This guidance is only included in the RIT–D application guidelines as it is specific to the RIT–D requirements in the NER.
- Calculating market benefits (including worked examples) relating to load transfer capacity (when end users gain access to a back-up of power supply) and embedded generators.

Conversely, only the RIT–T application guidelines provide additional detail on valuing market benefits associated with cost savings in meeting environmental targets and benefits that accrue across regions. These also provide additional guidance and worked examples on calculating market benefits that relate to effects on the wholesale market. These effects include changes in the variable operating costs of supplying electricity to load, ancillary

6 AER, *Better regulation: Final decision — RIT–D and application guidelines*, August 2013, p. 6.

7 The AEMC defined interested parties as having the potential to suffer a material and adverse NEM impact from the preferred option in the context of granting interested parties the ability to raise RIT disputes. See AEMC, *Final report: Review of national framework for electricity distribution network planning and expansion*, September 2009, pp. 69–70.

8 For the purposes of clauses 5.16.4, 5.16.5, 5.17.4 and 5.17.5 of the NER, interested party means a person including an end user or its representative who, in the AER's opinion, has the potential to suffer a material and adverse NEM impact from the investment identified as the preferred option.

9 AER, *Final RIT-T*, June 2010, (14), 15(g).

10 Clause 5.17.4(c) of the NER states that a RIT-D proponent is not required to prepare a non-network options report if it determines, on reasonable grounds, that there will not be a non-network option that is a potential credible option or that forms a significant part of a potential credible option to address the identified need.

services costs and competition benefits. Finally, the RIT–T application guidelines provide a more detailed worked example on the calculation of market benefits in a way that captures option value. In our view, similar guidance could apply to the RIT–D.

2.2 Context of this review

We published the application guidelines in June 2010 for the RIT–T and August 2013 for the RIT–D. While we amended both RIT application guidelines in September 2017, these amendments were limited to those necessary to give effect to the repex rule change. At that time, we flagged that we would commence a larger-scale review of the RIT application guidelines. This review will capture issues identified within the COAG EC's RIT–T review, any issues arising from the repex rule change that are yet to be addressed, and other provisions in the application guidelines that require amendment.[11] The following sections provide background information on this recent work, leading to this review of the RIT application guidelines.

2.2.1 The COAG EC RIT–T review

In February 2017, the COAG EC published a report into the review of the RIT–T.[12] The COAG EC's RIT–T review considered the appropriateness, effectiveness and efficiency of the test.

Broadly, the review found that the RIT–T in its current form remains the appropriate mechanism to ensure that new transmission infrastructure in the NEM is built in the long term interests of consumers. However, it suggested we review our RIT–T application guidelines,[13] and made several specific recommendations, including:[14]

- For us to review the RIT–T application guidelines with a view to better reflecting the net system benefits of options, including those relating to system security and climate goals.
- For us to improve the level and accessibility of information relating to transmission networks to allow greater engagement by non-network service providers. This includes exploring better alignment of the RIT–T and RIT–D, particularly around the level of consultation required with non-network businesses and requirements to produce non-network reports under certain circumstances. The COAG EC recognised that if we identify any extensions to the RIT–T requirements, this could require a rule change.
- For the Australian Energy Market Commission (AEMC) to explore whether we should have greater oversight over the RIT–T process and to consider whether the NER should be subject to civil penalty provisions. The AEMC has since recommended the COAG EC

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11 See AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017*, accessed 4 January 2018, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017.

12 COAG EC, *RIT–T review*, 6 February 2017.

13 The recent Finkel Review echoed this recommendation, as well as the recommendations of the COAG EC to strengthen the RIT-T. See Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, pp. 132–133.

14 COAG EC, *RIT–T review*, 6 February 2017, p. 8.

make breaches of the RIT processes subject to civil penalty provisions. In particular, this relates to clauses 5.15.2(b), 5.15.2(c), 5.16.3(a), 5.16.4(a), 5.17.3(a), and 5.17.4(a) of the NER.[15]

This review will directly address the first two of these recommendations. We also encourage stakeholders to consider whether or how the introduction of civil penalty provisions would change the nature of the guidance that would be helpful for us to provide in the RIT application guidelines.

2.2.2 Repex rule change

We proposed the repex rule change, which was finalised by the AEMC in July 2017. This rule extends the RITs, which previously applied only to network augmentation expenditure decisions, to also cover network replacement or refurbishment decisions, as well network expenditure arising from asset de-rating decisions.[16]

Following from this broader application of the RITs, we consider there is value in providing additional guidance (including worked examples) on accounting for factors that are specific to repex. During the AEMC's rule change consultation process, some stakeholders suggested we provide guidance on:

- Calculating costs that are unique to repex, such as costs resulting from the disposal of existing assets.[17]
- How to determine the total cost of a potential investment in determining whether it meets the RIT cost threshold when it has both replacement and augmentation drivers.[18]
- Treatment of asset replacement programs such as when the NSP plans to replace multiple assets of the same type across more than one location in the same year.[19]

2.2.3 Compliance monitoring of the RITs

We have been monitoring the application of the RITs since their commencement in June 2010 for the RIT–T and August 2013 for the RIT–D. Since then, we either have or are currently reviewing or monitoring:

- 18 applications of the RIT–T;
- 17 applications of the RIT–D; and

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15 AEMC, *Rule determination: National Electricity Amendment (Contestability of energy services) Rule 2017*, December 2017, p. 130.

16 AEMC, Rule *determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. ii.

17 SA Power Networks raised this in SAPN, *AEMC draft rule determination—Replacement expenditure planning arrangements*, June 2016, pp. 3-4.

18 Ergon Energy raised this in Ergon, *Submission on national electricity amendment (replacement expenditure planning arrangements) rule 2016*, November 2016, pp.11-12.

19 AEMC, Rule *determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 68

- One RIT–D dispute.

Through these activities, we have identified areas where there has been a lack of clarity around how RIT proponents can best apply the RITs. We elaborate on many of these areas in sections 4 and 5, which cover whether we should provide further guidance on how RIT proponents should:

- Select the base case;
- Perform sensitivity analysis, including how best to forecast and whether or not to vary multiple parameters at once;
- Select an appropriate discount rate;
- Engage with non-network proponents, including what level of detail RIT proponents should include in non-network options reports under the RIT–D; and
- Provide particular information to stakeholders in situations when they cancel a RIT.

2.3 Related projects

Other regulatory mechanisms complement the RITs in their role to:

- Provide transparency around the identification of efficient network planning options; and
- Facilitate network businesses to engage with energy market stakeholders in the network planning process.

It is helpful to consider the current RITs and RIT application guidelines in the context of these complementary mechanisms; many of which we have recently improved, or are currently improving. For instance:

- Network businesses must conduct annual planning reviews to identify the level of investment required to efficiently deliver network services. Network businesses then publish 'annual planning reports' (APRs) — DAPRs for distribution and TAPRs for transmission. These reports provide public information on emerging network constraints, including potential options to alleviate these constraints. In making this information publicly available, APRs increase the opportunities for non-network service providers to propose options to meet those needs. This includes for both smaller investments and in the event that a network business commences a RIT assessment.
- The distribution network planning and expansion framework requires distribution businesses to engage with non-network service providers by having a demand side engagement strategy and maintaining a demand side engagement register.[20] Also, our demand management incentive scheme will soon come into effect. This scheme will incentivise distribution businesses to undertake a transparent market testing process and to manage demand as part of its preferred option when doing so is efficient.[21]

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20 AEMC, *Rule determination: National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012*, October 2012, pp. i–iii.

21 AER, *Explanatory statement: Demand management incentive scheme — Electricity distribution network service providers*, December 2017.

- In June 2017, we published a distribution DAPR template (or more formally, the system limitations template).[22] The DAPR template aims to improve the consistency and useability of DAPRs across the NEM, thereby making it easier for non-network service providers to identify and propose solutions to address identified network needs. We are also developing TAPR guidelines that should provide for a consistent format across TAPRs.[23] By achieving this, TAPR guidelines should support the consistent provision of information by transmission businesses across the NEM.
- Following the repex rule change in July 2017, network businesses will expand the scope of their APRs to also include network asset retirement and de-rating information.[24]

22 AER, *Final decision: Distribution annual planning report template V1.0*, June 2017.

23 NER clause 5.14B.1. This follows from AEMC, *Rule determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, May 2017.

24 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017.

3 The role of the RITs in promoting the long term interest of consumers

Under the NER, the purpose of the RITs is to is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the relevant market (the preferred option).[25]

To provide effective guidance on the RITs, it is also important to understand how the RITs contribute to achieving the National Electricity Objective (NEO) that is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity.[26] This section highlights why it is in the long-term interests of electricity consumers to have a framework specifying how network businesses must identify preferred options.

In our view, the RITs promote the long-term interests of electricity consumers in two different, yet related, ways. These include promoting competitive neutrality and investment efficiency.

3.1 Promoting competitive neutrality

The NEM relies on competition to deliver good outcomes for consumers in the contestable parts of the market. Commercial unregulated investment in key assets, such as new generation facilities, storage or new demand response facilities is required for that competition to be effective. The RIT framework recognises that regulated network assets can be both a substitute and a complement for these contestable assets and therefore promotes competitive neutrality in two different ways:

- By limiting the ability of network businesses to make investments that do not pass a cost–benefit analysis, the RITs foster and promote the use of third-party non-network investment in the NEM, thereby promoting competitive outcomes in the contestable part of the sector. This effect of the RIT will often be more relevant for large, transmission investments. For instance, the business case for a generation investment in a strategic location could be undermined if a regulated network business over-built the transmission network, while earning a regulated return on that investment.
- By requiring network businesses to consider all credible options before undertaking major investments in the network, they promote the use of third party-provided non-network options, where efficient. This aspect of the RITs is important for promoting competitive neutrality to the extent that our regulatory framework does not sufficiently, in of itself, incentivise network businesses to engage with non-network options and third party providers where efficient. The RITs can result in a RIT proponent procuring non-network services, which it may not have otherwise considered, as being the option with the highest net benefit. By requiring RIT proponents to consider non-network options

25 See NER clauses 5.16.1(b); 5.17.1(b).
26 National Electricity Law, Section 7.

when applying RITs, this increases the ability of the contestable non-network services market to develop and operate more effectively.

Promoting competitive neutrality is consistent with:

- The original purpose of the regulatory test (the predecessor of the RITs), which relied on 'the key principles of economic efficiency and competitive neutrality' and a 'traditional cost-benefit analysis framework but with a number of qualifications to limit any adverse impacts that regulated network investments might have on the contestable parts of the industry'.[27]
- The COAG EC's observation that the RIT-T 'aims to ensure that all credible options for addressing an identified need are considered, and that the relative merits of network and non-network options are considered on an equal footing'.[28]
- Our strategic objective to drive effective competition where it is feasible.[29] This promotes the long-term interest of consumers by improving efficiency, innovation and consumer choice.

3.2 Promoting efficient network decision making

A further benefit of the RITs is that they provide transparency to complement the efficiency incentives under the ex-ante incentive regulatory regime. In doing so, the RITs and incentive regulation work together to prevent inefficient regulated network investments.

While we already incentivise network businesses to invest efficiently by providing them with an ex-ante allowance and permitting them to earn a share of any savings they make against that allowance, there is still value in having additional transparency and accountability in the investment decision-making process because regulatory incentives do not always operate as intended. For example, setting an allowed expected rate of return that is higher than is necessary to attract investment would, all else being equal, incentivise network businesses to incur a higher than efficient level of capex:

Moreover, the RITs help promote the long-term interest of consumers by providing an additional mechanism (on top of the ex-ante incentive framework) that promotes network businesses only recovering revenue from consumers when efficient. The RITs promote this in several ways, including:

- As part of a regulatory determination on a network business's capex, we can approve additional capex for 'contingent projects', which are approved projects that are only recovered in the revenue capex if predefined trigger events occur. This ensures that customers only incur the costs of projects which are necessary during the regulatory control period. It has been our recent practice to include as triggers: 1) successful

27 AER, *Review of the regulatory test — Decision*, 11 August 2004, p. 17

28 COAG EC, *RIT–T review*, February 2017, 10.

29 AER, *Statement of intent 2017–18*, September 2017, p. 2.

completion of a RIT, and 2) a determination by us that the investment satisfies the RIT'.[30] In this context, the RITs are a key part of our assessment of prudent and efficient costs, which helps us set an efficient capex allowance under uncertainty.

- If a network business overspends its capex allowance, the NER allows us to consider the network business' actual expenditure, including RITs across relevant projects in conducting an ex-post review to assess the efficiency of any capex overspend. If we assess that capex is reasonably likely to be efficient, we can roll it into the RAB so the network business can earn an expected rate of return on its efficient capex. Conversely, if we assess that additional capex as inefficient, we would exclude it from the RAB so the network business does not earn an expected return on its inefficient capex. Relevantly, the RITs help us assess the efficiency of capex so that:
    - If the capex overspend was efficient, network businesses still earn a return on efficient capex, which supports network businesses in providing a safe, reliable and secure supply of electricity.
    - If network businesses incur inefficient capex overspends, we can prevent electricity consumers from paying for these inefficiencies.
- If we provide a capex allowance that is inefficiently high, the network business might undertake inefficient investment without being scrutinised by an ex-post review (this differs from the above point in that we can apply an ex-post review if there have been capex overspends). If inefficient capex is not subject to an ex-post review, it will be included in RAB, where it can earn a return over the life of the assets. In this context, the RITs provide a safeguard to prevent inefficient expenditure, as major capex projects still need to pass a transparent cost–benefit analysis before they can occur.

As such, requiring network businesses to run a transparent cost-benefit analysis promotes the long-term interest of consumers, in part, because it provides an efficiency assessment of individual projects. This assessment complements other efficiency incentives under the regulatory regime. In our view, this is consistent with the COAG EC's observation that 'the role of the RIT–T is to avoid inefficient regulated investment in new transmission assets, including interconnectors, in the NEM'. [31] It is also consistent with COAG EC's view that, 'the RIT–T is designed to be a consultative and transparent process for transmission planning. The test allows for public consultation and comment within a transparent framework'.[32]

Question 1: Do you agree that the RITs promote the long-term interests of consumers by promoting competitive neutrality and investment efficiency? Are there any other factors we should consider?

30 There a few interrelationships between RITs and regulated revenues. As an example, For example, see AER, *Final decision TransGrid transmission determination 2015–16 to 2017–18: Attachment 6 — Capital expenditure*, April 2015, Appendix D.

31 COAG EC, *RIT–T review*, February 2017, 10.

32 COAG EC, *RIT–T review*, February 2017, 10.

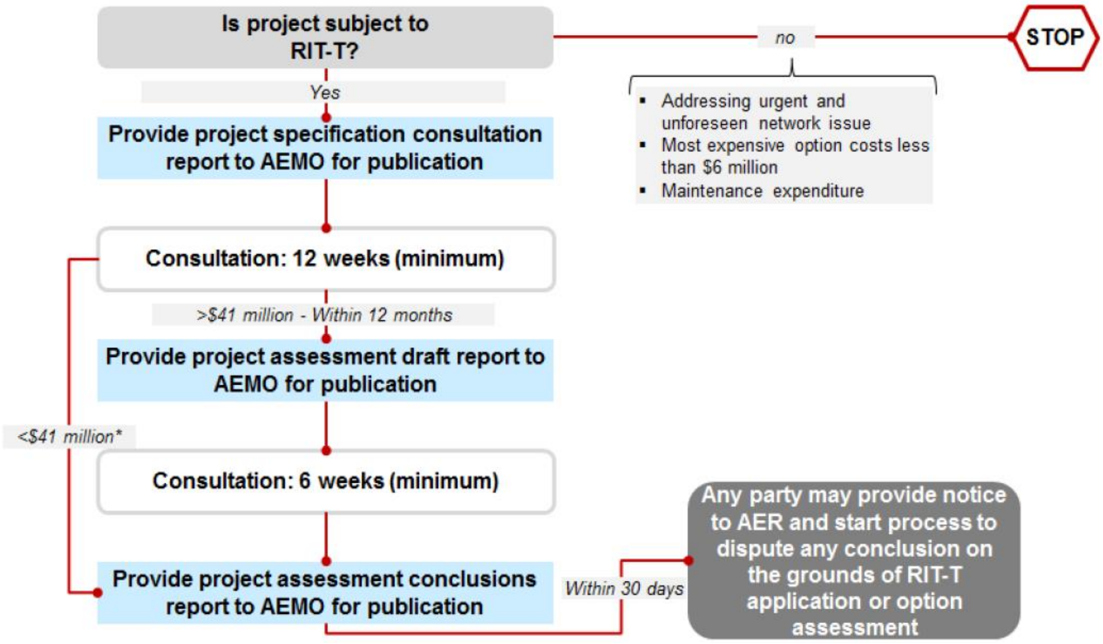
4 Issues relating to the RIT process

The NER prescribe the process for and operation of the RITs, including the dispute resolution process. The first step of the process involves a proponent identifying whether a RIT applies. After a RIT proponent determines that it must apply a RIT, it must follow the following process:

1. Develop a consultation report to consult with stakeholders on the project. For a:
   - RIT–T, this will be a project specification consultation report. The proponent will receive submissions over at least 12 weeks, which it will assess in determining a list of credible options and classes of material market benefits.
   - RIT–D, if a non-network option is, or forms a significant part of, a potential credible option, this will be a non-network options report which the proponent must consult on for at least three months. Otherwise, the proponent must publish a notice under clause 5.17.4(d) of the NER.
2. Unless the project meets conditions for exemption, the proponent must develop a draft report outlining its proposed RIT outcome for consultation over six weeks. This is a project assessment draft report for a RIT–T or a draft project assessment report for a RIT–D.
3. Assess submissions and develop a report outlining the outcome of its RIT — a project assessment conclusion report for a RIT–T or a final project assessment report for a RIT–D.
4. Parties can lodge disputes within 30 days of the report, which will require the AER to make a decision on that dispute.

Figure 1 and figure 2 summarise these processes for the RIT–T and RIT–D, respectively.

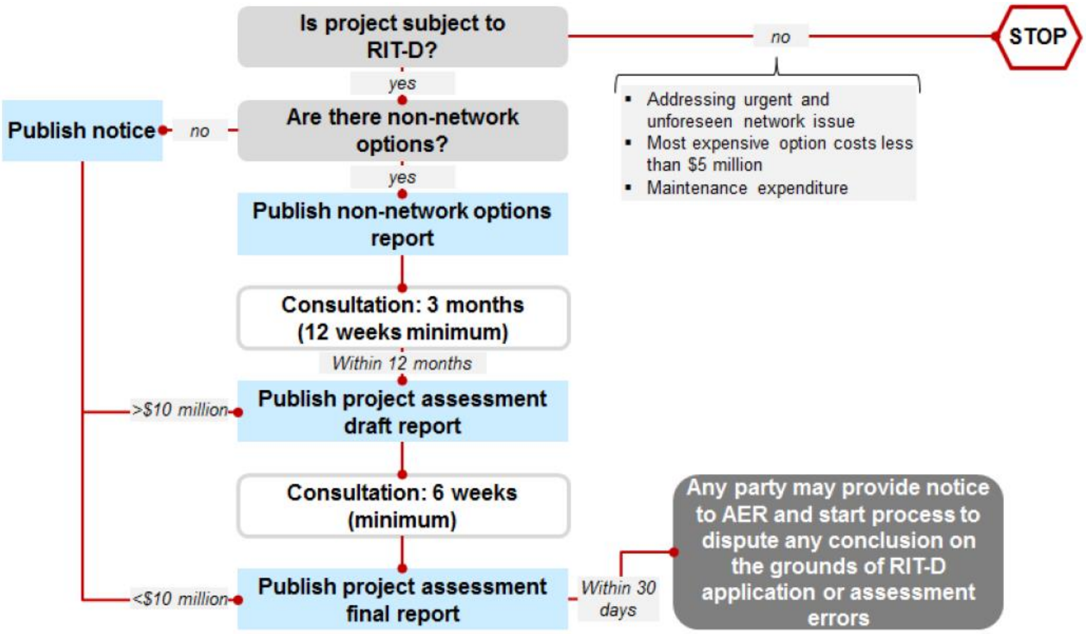
Figure 1: RIT–T process



*   Other requirements are: no material market benefit, the transmission business has identified its preferred option in the consultation report, and submissions on the consultation report did not identify any additional credible options which could deliver a market benefit.

Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 65.

Figure 2: RIT–D process



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.

The following sections set out the areas of the above processes that we intend to consider as part of this review. These areas include:

- When we should apply some of the RIT exemptions in the NER.
- Whether we should be providing clearer guidance on and/or closer oversight of how distribution businesses engage with non-network service providers when publishing their non-network options report under step 1 above.
- Whether we should be providing guidance to support network businesses in engaging with consumers when apply a RIT.
- Whether we can or should be doing more to align the processes between the RIT–T and RIT–D, particularly in consulting on non-network options.
- Whether there should be clearer guidance on the information network businesses should provide when they cancel RIT assessments.

4.1 When do the RITs apply?

The NER include a number of exceptions to the requirement to undertake a RIT. These are summarised in Table 3.

Table 3: RIT exemptions provided in the NER

#	RIT–T	RIT–D
1	The project is required to address an urgent and unforeseen network issue that would otherwise put at risk the reliability of the transmission network.	The project is required to address an urgent and unforeseen network issue that would otherwise put at risk the reliability of the distribution network or a significant part of that network.
2	The estimated capital cost of the most expensive option to address the identified need which is technically and economically feasible is less than $6 million.*	The estimated capital cost to the network businesses affected by the RIT-D project of the most expensive potential credible option to address the identified need is less than $5 million.*
3	The proposed expenditure relates to maintenance and is not intended to augment the transmission network or replace network assets.	The project is related to the maintenance of existing assets and is not intended to augment a network or replace network assets.
4	The proposed relevant network investment is a reconfiguration investment undertaken by a transmission business with an estimated capital cost of less than $6 million* or which has, or is likely to have, no material impact on network users.[33]	N/A
5	The identified need can only be addressed by expenditure on a connection asset which provides services other than prescribed transmission services or standard control services.	
6	The cost of addressing the identified need is to be fully recovered through charges other than charges in respect of prescribed transmission services or standard control services.	
7	The proposed expenditure relates to protected event emergency frequency control scheme investment and is not intended to augment the transmission network or replace network assets.	The proposed expenditure relates to protected event emergency frequency control scheme investment and is not intended to augment a network.

Source: Clauses 5.16.3(a) and 5.17.3(a) of the NER.

* Clause 5.16.3(a)(2), 5.17.3(a)(2) of the NER. The RIT–T cost threshold is currently $6 million and the RIT–D cost threshold is currently $5 million. See AER, *Final determination: Cost thresholds review for the regulatory investment test*, November 2015, p. 10.

Although there is a slight difference between the wording of the RIT–T and RIT–D exceptions for projects that do not meet the relevant cost thresholds (see item 2 of table 3 above), our view is that this difference does not affect the interpretation of those provisions. A project is exempt from a:

33 A reconfiguration investment re-routes one or more paths of a network for the long term and has a substantial primary purpose other than the need to augment a network.

- RIT–T if the estimated capital cost of the most expensive option to address the identified need that is technically and economically feasible is less than the RIT–T cost threshold.[34] Since the NER refer to the capital cost of an option, an external financial contribution would produce an exemption if it reduced the capital cost of the option to be below the RIT–T cost threshold.
- RIT–D if the estimated capital cost to the network businesses affected by the RIT–D project of the most expensive potential credible option to address the identified need is less than the RIT–D cost threshold.[35] An external financial contribution would produce an exemption if it reduced the capital cost to network businesses affected by the RIT–D project to be below the RIT–D cost threshold.

That is, in both cases, our view is that a RIT is not required where the external financial contribution results in the project falling below the cost threshold. In these circumstances, the external financial contribution means that, to the extent of that contribution, the costs of the project do not need to be recovered from consumers via the network business's regulated charges.

This position is consistent with the COAG EC's view that:[36]

> *The RIT is designed to identify the most efficient regulated investment in transmission infrastructure;*

that;

> *the RIT-T plays the role of gate-keeper—ensuring that consumers only pay for investments that are economically efficient and optimal overall for the NEM;*

and that;

> *the RIT-T only applies to investments that will benefit from regulated revenues; that is, regulated revenues recovered from electricity consumers. It does not apply to investments that are funded from other sources, for example augmentations paid for by generators, merchant interconnectors, or investments funded by governments.*

Question 2: Do you agree that a RIT assessment is not required where the external financial contribution results in the project falling below the cost threshold?

4.2 Consumer engagement and the RITs

The RIT application guidelines currently provide limited guidance on how RIT proponents can effectively engage with consumers when applying RITs. This differs from guidance on

34 Clause 5.16.3(a)(2) of the NER. The RIT–T cost threshold is currently $6 million. See AER, *Final determination: Cost thresholds review for the regulatory investment test*, November 2015, p. 10.

35 Clause 5.17.3(a)(2) of the NER .The RIT–D cost threshold is currently $5 million. See AER, *Final determination: Cost thresholds review for the regulatory investment test*, November 2015, p. 10.

36 COAG EC, *RIT–T review*, February 2017, 4, 10.

facilitating non-network engagement in the RIT application process, which the NER specifies and the RIT application guidelines provide (see sections 4.3 and 4.4).

The Consumer Challenge Panel (CCP) has raised the importance of consumer engagement under the RITs.[37] It observed that, in the context of the RITs, 'effective consumer engagement is important as is the engagement of providers of non-network solutions and other stakeholders'.[38]

We acknowledge the need to direct greater attention towards how to best promote consumer engagement in the RIT application process. While some network businesses have engaged with consumers throughout the RIT application process, the RIT application guidelines provide limited guidance on how network businesses can effectively engage with consumers.[39] Given this, we consider there is value in enhancing the RIT application guidelines to promote a consistent, best-practice approach to consumer engagement throughout the RIT application process.

Question 3: How do you think we should amend the RIT application guidelines to better facilitate consumer engagement throughout the RIT application process?

4.3 Screening for non-network options

Requirements to screen for non-network options and publish a non-network options report are specific to the RIT–D. Under the NER, a RIT–D proponent must either:[40]

- Publish a non-network options report for consultation. These reports provide information to assist non-network service providers in presenting alternative potential credible options for the RIT–D proponent to consider; or
- Determine, on reasonable grounds, that no non-network options will be or form part of a potential credible option for the RIT–D project to address the identified need under clause 5.17.4(c). When making this determination, a RIT–D proponent must publish a notice setting out the reasons for this determination, including any methodologies and assumptions it used ('a clause 5.17.4(c) notice').

Since the NER are prescriptive on the information required under the non-network options report, the RIT–D application guidelines provide little additional guidance to what the NER

37 CCP, *Contingent projects and consumer interest*, 17 October 2017. In particular, the CCP discussed the importance of the RITs in the context of contingent projects. These are projects we include in our regulatory determinations, where the associated expenditure does not form a part of the capex allowance. We link expenditure associated with contingent projects to defined 'trigger events' that must be probable during the relevant regulatory period. Our practice has been to include the completion of a RIT as a trigger event.

38 CCP, *Contingent projects and consumer interest*, 17 October 2017, p. 7.

39 For an example of consumer engagement when applying a RIT, see TransGrid, *Community and stakeholder resources - Powering Sydney's Future*, accessed 12 February 2018, https://www.transgrid.com.au/news-views/lets-connect/consultations/consultations-archive/Pages/Powering-Sydney.aspx.

40 NER clauses 5.17.4(b)–(e).

already prescribe.[41] The RIT–D application guidelines provide some additional guidance on screening for non-network options and clause 5.17.4(c) notices.[42] For example, they require that a clause 5.17.4(c) notice must explain, for every non-network option available, why this option:

- could not address the identified need; and
- is not commercially feasible; or
- is not technically feasible; or
- could not be implemented in a sufficient time to meet the identified need; and
- does not satisfy all of the above requirements when forming a significant part of a credible option.

Our initial view is that there could be value in providing clearer guidance on how distribution businesses can best use their non-network options reports and non-network screening requirements to engage with non-network service providers. We could also complement this by providing closer oversight over these activities.

It is important that non-network engagement and reporting is effective so non-network proponents can propose effective and efficient non-network options. Our assessment of the RIT–Ds undertaken to date has shown that there have been inconsistent levels of non-network engagement and information in reports, particularly in the non-network options report.

Question 4: What specific guidance would help distribution businesses better use their non-network options reports and non-network screening requirements to engage with non-network service providers? Are there specific ways we should complement this guidance with greater oversight over distribution business' non-network engagement activities?

4.4 Scope for more consistency between the RITs

In its RIT–T review, the COAG EC suggested we further examine the RIT–D requirements that do not extend to transmission. In particular, the COAG EC felt we should explore the RIT–D requirements to consult with non-network providers and to produce non-network options reports under certain circumstances. Any extension of these requirements to transmission businesses should have the objective of ensuring RIT–T proponents effectively test the market for competitive options.[43]

As discussed earlier in section 4.3, the requirements for RIT–T and RIT–D proponents differ when consulting with non-network providers at the start of the process. Only the RIT–D requires proponents to screen for non-network options and consult on a non-network options

41 AER, *RIT–D application guidelines*, September 2017, pp. 11–13.
42 AER, *RIT–D application guidelines*, September 2017, pp. 26–28.
43 COAG EC, *RIT–T review*, February 2017, 25.

report for at least three months, if a non-network option is or forms a significant part of a potential credible option.

While the RIT–T does not include these requirements, non-network engagement is still important for transmission businesses, with the NER requiring RIT–T proponents to:[44]

- Consult all registered participants, the Australian Energy Market Operator (AEMO) and interested parties on the RIT–T project. This is where an 'interested party' is a person, including an end user or its representative who, in our opinion, has the potential to suffer a material and adverse NEM impact from the investment identified as the preferred option. Also, a 'registered participant' is a person who AEMO has registered in any of the categories listed in NER rules 2.2 to 2.7 — which would cover various non-network service providers such as generators, customers, small generation aggregators, market ancillary service providers, market participants and metering coordinators.
- Prepare a project specification consultation report that describes the identified need. This must include any assumptions used in identifying the need, as well as its technical characteristics that a non-network option would have to deliver, a discussion relating to it and any associated credible options in AEMO's national transmission network development plan (if applicable), and detailed information on all credible options that could address it.
- Consult on the credible options and issues addressed in its project specification consultation report for no less than 12 weeks.
- Include in its project assessment draft report, a summary and commentary on the submissions to its project specification report, as well as detailed information on its assessment of credible options in proposing its preferred option.
- Consult on its proposed preferred option and the issues addressed in its project assessment draft report for no less than six weeks.
- Prepare a project assessment conclusions report, setting out the matters detailed in the project assessment draft report and a summary of, and its response to, any submissions received on its project assessment draft report.

Our initial view is that this above process should sufficiently accommodate the level of consultation required under the RIT–T process for ensuring proponents effectively test the market for competitive options. However, we agree that these above requirements are less prescriptive with regards to screening for and consulting on non-network options than what the NER describe for the RIT–D. Given this, we consider there will be value in expanding the guidance in the RIT–T application guidelines to clarify that:

- While transmission businesses are not required to have a demand-side engagement register, it is best practice to consult with these parties throughout the RIT–T process (notwithstanding that non-network service providers classified as interested parties or registered participants should already being consulted).

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44 NER clause 5.16.4.

- The project specification consultation report should include the same information that a non-network options report would include. As a general rule, the project specification consultation report should include sufficient information to assist non-network service providers to present alternative potential credible options for the RIT–T proponent to consider.

Question 5: Do you agree that the RIT–T process accommodates the consultation required for proponents to effectively test the market, but would benefit from guidance to better align information provided in the project specification consultation report with that provided in the non-network options report under the RIT–D? Alternatively, would it be preferable to request a rule change for non-network consultation under the RIT–T to more closely mirror what the NER require for the RIT–D?

4.5 Cancellation of RIT assessments

The NER describe when a RIT proponent must re-apply a RIT. This must occur if a material change in circumstances means that, in the reasonable opinion of the RIT proponent, the preferred option identified in the project assessment conclusions report or final project assessment report is no longer the preferred option.[45]

However, it is also reasonable that a material change in circumstances may lead to the identified need no longer existing, even mid-way through the RIT process. This may lead a RIT proponent to cancel its RIT assessment before completing the RIT process. For example, a RIT–T proponent may publish a project specification consultation report, only for its customers to later advise that, due to a material change in circumstances, the identified need no longer exists.

Section 3.5 if the RIT–D application guidelines and section 4.4 of the RIT–T application guidelines prescribe processes for reapplying RITs after there has been a material change in circumstances.[46] However, there is little guidance on what information a RIT proponent must publish when it cancels a RIT assessment mid-way through the RIT process. We consider there is value in providing transparency around decisions to cancel semi-completed RIT assessments following a material change in circumstances.

We have seen instances where network businesses have provided a low level of detail in their cancellation notices for RITs, which raises questions of transparency. We consider stakeholders and network businesses would benefit from the RIT application guidelines providing more guidance on the level of detail we would expect RIT proponents to provide in explaining a decision to cancel a RIT assessment. We consider this would be valuable for increasing the transparency around the process for cancelling RITs.

45 NER clauses 5.16.4(z3)(2) and 5.17.4(t)(2).

46 See AER, *RIT–T application guidelines*, September 2017, pp. 46–47 and AER, *RIT-D application guidelines*, September 2017, pp. 15-17.

Question 6: What additional guidance should the RIT application guidelines provide regarding the information network businesses should publish when they cancel RIT assessments?

5 Issues relating to the application of the RITs

Some of the key issues relating to the application of the RITs are set out below. These include how RIT proponents:

- describe an identified need;
- estimate option value and conduct their sensitivity analysis;
- apply the RITs to replacement expenditure following the repex rule change;
- account for external funding that they receive for RIT projects;
- treat high impact, low probability events;
- account for the external policy environment;
- select the discount rate and treat risks;
- select an appropriate value of customer reliability; and
- select a base case for its cost–benefit analysis.

5.1 Identified need

The NER define an identified need as the objective a network business seeks to achieve by investing in the network.[47] Under the NER, a network or a non-network option can address an identified need.

The current RIT application guidelines specify that an identified need may consist of:[48]

- meeting any of the service standards linked to the technical requirements of schedule 5.1 of the NER, or in applicable regulatory instruments (that is, reliability corrective action);[49] and/or
- an increase in the net economic benefit in the NEM.[50]

While the definition of 'identified need' in the NER is broader than these two examples,[51] these examples correctly encompass the outcomes that, in practice, an option identified in a RIT must achieve to be a preferred option under the RIT. This is because any preferred option must have a positive net economic benefit unless the identified need is for reliability corrective action.[52]

47 NER, chapter 10.
48 AER, *RIT–T application guidelines*, September 2017, p. 7; AER, *RIT–D application guidelines*, September 2017, p. 7.
49 NER, clause 5.10.2.
50 The RIT application guidelines describe this as an increase in the sum of consumer and producer surplus in the NEM, which has the same effect as an increase in the welfare of consumers and producers in the NEM, or the net economic benefit in the NEM.
51 NER, chapter 10
52 NER cl. 5.16.1(b), 5.16.1(c)(12), cl. 5.17.1(b), 5.17.1(c)(9)(v).

While the current RIT application guidelines are correct on this matter, we consider it is worthwhile providing greater clarity on this point.

Our assessment of the RITs to date has identified instances where some network businesses characterise network augmentation or replacement to assist a particular generation investment as an identified need to meet in itself, rather than as a means of meeting service standards or increasing the net economic benefit in the NEM. Assisting generation investment may technically be an identified need if it is the objective a network business seeks to achieve by investing in the network,[53] (although credible options to meet this need must also be commercially and technically feasible).[54] However, a credible option must also maximise net economic benefit to be a preferred option (although such maximisation may nevertheless yield a net economic cost where the identified need is reliability corrective action).

Given this, we consider a RIT assessment would be clearer if the RIT proponent expressed their identified need as the achievement of an objective that is consistent with identifying a preferred option. For instance, assisting generation investment is not consistent with identifying a preferred option if it is not motivated by correcting or avoiding reliability problems or producing a net economic benefit in the NEM. In such circumstances, if network businesses are to express an identified need in the form of assisting a particular participant or investment, they should only do so after considering the full range of potential generation, storage or demand-side investments that could be facilitated by regulated network investment. Doing this should ensure that such investment is appropriately directed towards maximising net economic benefit.

We consider further clarity should be provided in this area, since the description of an identified need for any RIT project is important for meeting the requirements of the NER. While we consider that the RIT application guidelines should not be overly prescriptive, specific examples to demonstrate the intent of the NER on the description of an identified need may better guide network businesses in applying RITs. This guidance should also assist RIT proponents in applying RITs to address a network need arising from the efficient retirement of poor condition assets (replacement projects), where we currently provide limited guidance.

Question 7: Do you agree with our proposed approach of providing further guidance on how RIT proponents should describe an identified need?

5.2 Option value and scenario analysis

One of the key issues highlighted under the COAG EC's RIT–T review was providing more clarity around the incorporation of option value. This is where COAG EC defined 'option value' as:[55]

53 This is consistent with NER, chapter 10.

54 NER cl. 5.15.2(a)(2).

55 COAG EC, *RIT–T review*, February 2017, p. 25.

a benefit that results from retaining flexibility in a context in which certain actions are irreversible (sunk), and new information may arise in the future as to the payoff from taking a certain action.

The COAG EC recognised that option value can already be included within the RIT–T. However, it also found:[56]

a number of stakeholders do not consider that option value is adequately explained in the AER RIT–T application guidelines with some concerned that not all option values are able to be adequately captured. It is clear there is uncertainty amongst some stakeholders as to how the option value of a project should be determined.

The application guidelines for both the RITs currently provide guidance on how RIT proponents should account for uncertainty through applying scenario analysis, and in doing so, capture option value.[57] We agree there is scope to provide more clarity and updated examples to expand the current guidance.

Our current preference is to include further guidance to provide more clarity on:

- Conducting a more robust scenario analysis, recognising that in many of the RIT–Ds to date, proponents often only vary one parameter for each of the scenarios/sensitivities tested.[58] Consistent with advice provided to us during a recent RIT–D dispute, we recognise there may be RIT–Ds where it is appropriate to take a broader approach to this analysis, where proponents vary multiple key parameters at a time.[59]
- Calculating option value, by providing a more detailed worked example of a decision-tree approach (or other approaches).[60] Given that some non-network options may have relatively high option value due to the relatively low up-front costs and short commissioning times they offer, we consider there would be value in including a detailed worked example where the RIT proponent calculates the option value associated with a non-network option.
- Developing and assessing reasonable scenarios of future supply and demand to encourage network businesses to adopt a more consistent approach to forecasting different states of the world.

Question 8: Is there any specific guidance you would like us to provide in clarifying how RIT proponents should calculate option value, make forecasts and test different states of the world? Are there particular

56 COAG EC, *RIT–T review*, February 2017, p. 26.

57 AER, RIT–*D application guidelines*, September 2017, pp. 29–30, 61; AER, *RIT–T application guidelines*, September 2017, pp. 34–38, 74.

58 HoustonKemp, *Consistency of SAPN's Kangaroo Island RIT–D with the regulatory requirements: Final report*, April 2017, p. 28.

59 HoustonKemp, *Consistency of SAPN's Kangaroo Island RIT–D with the regulatory requirements: Final report*, April 2017, pp. 24–25.

60 It is worth noting that the RIT–T application guidelines already provide some guidance on this in example 15. See AER, *RIT–T application guidelines*, September 2017, pp. 35–37.

scenarios where a worked example would be helpful in providing this guidance?

5.3 Replacement expenditure

In July 2017, the AEMC made the replacement expenditure (repex) rule change. Among other changes to the NER, this extended the RITs to network repex decisions. The repex rule change also aligned the RIT–T with the RIT–D requirement for the proponent to retake the test where there is a material change in circumstances, unless we determine otherwise. The rule included transitional arrangements requiring us to amend and publish RIT documentation to take into account the amending rule by no later than 18 September 2017.[61]

In September 2017, we made the necessary amendments to the RIT application guidelines to accommodate the repex rule change. These amendments included updating the following:[62]

- Our cost threshold references;
- NER clause references throughout the RIT–T application guidelines to address the renumbering of clauses; and
- Removing italicised terms from the RIT–T application guidelines for consistency with the RIT–D application guidelines.

The above amendments were necessary, but we also consider additional guidance would be desirable. In particular, we see value in providing additional guidance on:

- How network businesses should treat asset replacement programs under the RITs. This follows from the AEMC's repex rule change determination, which stated:[63]

  > *if a network service provider plans to replace multiple assets of the same type across more than one location in the same year it may not trigger the capital cost threshold if these assets are addressing more than one identified need. The AER may provide more guidance on the treatment of asset replacement programs in its regulatory investment test application guidelines.*

- Assessing options that entail a combination of augmentation expenditure and repex.
- Estimating costs unique to repex projects, including the provision of worked examples.
- The treatment of committed and anticipated projects as raised in the context of the repex rule change.

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61 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

62 See AER, RIT-*T and RIT-D application guidelines (minor amendments) 2017*, accessed 3 January 2018, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017.

63 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. 68.

In addition, we are also working with the industry on how to undertake the risk assessment that is required to demonstrate efficient asset retirements. An industry wide workshop was held in October 2017 to facilitate this. We will clarify the annual planning reporting requirements on asset retirements, and outline a good practice approach to the asset retirement decisions. We consider this would supplement the additional guidance on asset-retirement decisions (leading to a network need and investment, which may lead to asset replacement), which we intend to provide in the RIT application guidelines.

Question 9: Would any guidance in addition to the areas listed in section 5.3 of this issues paper assist in the application of the RITs to repex projects? Is there particular guidance stakeholders would like to help understand how the RITs will apply to asset replacement programs?

5.4 Accounting for external funds when applying RITs

Consistent with section 4.1, a RIT assessment is required for projects that a government body or private party partially funds if the remaining costs recovered through prescribed transmission services or standard control services exceed the RIT cost threshold. This section relates specifically to these cases in providing guidance on how to account for external funds in RIT applications.

Since the RIT is a market-wide cost–benefit analysis,[64] funds that move:

- Between parties within the market count as a wealth transfer and should not affect the calculation of the final net-benefit under the RIT. This is consistent with the current RIT application guidelines, which specify that RIT proponents should treat as an externality, the economic impacts that accrue to parties other than those who produce, consume and transport electricity in the relevant market.[65] An implication of this is that if a commercial electricity market participant, like a generator, provided funding for a RIT project, this contribution would be treated as a wealth transfer and would have no impact on the final net benefit calculated under the cost–benefit analysis.
- From a party outside the market to a party within the market should count as a reduction in the costs of the option. This funding should consequently increase the final net-benefit calculated under a RIT. An implication of this is that if a government or government body provided funding for a RIT project, this contribution would be treated as a reduction in the costs of the option and would increase the final net benefit calculated under the cost–benefit analysis.

Question 10: Do you agree that the RIT is a market-wide cost–benefit analysis? Do you agree that, as a consequence of this, funds that move

64 The purpose of the RITs is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market ('the preferred option'). This is where market is the NEM for the purposes of the RIT–D. For the RIT–T, this is any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO. See NER chapter 10 and clauses 5.16.1(b) and 5.17.1(b).

65 AER, *RIT–T application guidelines*, September 2017, p. 38, AER, *RIT–D application guidelines*, September 2017, p. 53.

between parties within the market should not affect the final net-benefit, but funds that comes from outside the market to a party within the market should increase the final net benefit?

5.5 Treatment of high impact, low probability events

In its RIT–T review, the COAG EC recommended that when we review our application guidelines, we should provide guidance on how to better account for high impact, low probability events, such as the 'black system' event experienced in South Australia in 2016. The COAG EC felt that the methodologies set out in the current application guidelines should be adapted to weight these events, in line with public expectations regarding mitigation. To capture the implications of these events, it felt we would need enhanced modelling tools and processes to better capture system security benefits.[66]

It is worth noting that AEMO considered that the current RIT–T could already capture the benefits of bringing forward 'low-regret upgrades',[67] including the capability of these upgrades to share supply in the event of a high impact, low probability outage. While it found these benefits were not always properly considered, this was more of an issue for early-stage prefeasibility assessments than it was for the RIT–T.[68]

Similarly, our initial view is that the consideration of high-impact, low probability events, including in the assessment of 'low-regret upgrades', is compatible with the current RIT application guidelines. RIT proponents would account for high impact, low probability events via its scenario analysis. It is also worth noting that our suggestion to provide further guidance on varying multiple parameters at once when accounting for scenarios/sensitivities will assist in capturing the effects of more extreme events (see section 5.1). We also note that the AEMC has commenced its reliability frameworks review, which may ultimately result in changes to market settings and mechanisms relating to reliability.[69] To the extent this occurs, it could enhance the ability of the RITs to capture the ability of a credible option to avoid or mitigate high impact, low probability events.

However, given the importance of high impact, low probability events, we consider there may be value in expanding the RIT–T application guidelines to include a worked example on how to account for these events. Some of our initial views are that:

- Network businesses should value these events if there is a credible market value or values attached to them, such as the value of lost load.
- It is consistent with the RITs to include an extreme scenario in the scenario analysis, and weight it by some low probability of occurring.

66 COAG EC, *RIT–T review*, February 2017, pp. 4–6.
67 AEMO defines 'low-regret upgrades' as upgrades that will eventually be required in most reasonable future scenarios.
68 AEMO, *Integrated System Plan Consultation*, December 2017, pp. 51–2.
69 See AEMC, *Interim report: Reliability frameworks review*, 19 December 2017.

- If we receive submissions suggesting specific modelling tools or processes that could improve upon the methodologies described in current RIT application guidelines, we will consider incorporating these into our application guidelines.

Moreover, a key determinant of system security is the availability of ancillary services. We consider the RIT–T already captures the benefits of these services, which are associated with various credible options such as interconnectors and new generation facilities with certain characteristics. Further, through its frequency control frameworks review, the AEMC is examining changes to ancillary services arrangements that may enable additional value from the provision of ancillary services to be captured in a RIT–T assessment.[70] We are interested in stakeholder views on whether the RIT–T adequately better captures system security considerations, or whether the application guidelines should change to better facilitate the incorporation of system security benefits.

Question 11: Do you agree that the scenario analysis currently prescribed in the RIT application guidelines can sufficiently capture the effects of high impact, low probability events and system security requirements? Do the RIT–T application guidelines require expanding to assist proponents in accounting for these events? Is there specific guidance you would like on this topic, or particular scenarios where a worked example would be helpful—and how (if at all) should this differ between the RIT–D and RIT–T application guidelines?

5.6 Environmental policy and the National Energy Guarantee

One of the recommendations of the COAG EC's RIT–T review was for us to provide further guidance and clarity on the treatment of environmental policies in the RIT–T application guidelines. The RIT–T application guidelines currently provide guidance on how to account for the evolving technology and policy environment. Importantly, the effects of environmental policies can already be taken into account in the RIT–T, provided the policy is reasonably understood and predictable. Specifically environmental policies are taken into account in the benefits calculation of a RIT–T, which assesses how removing network congestion lowers the total cost of delivering an environmental policy set by government.

At a broad level, the current RIT application guidelines already incorporate guidance on how to account for the policy uncertainty, including around environmental policies. RIT proponents would already account for environmental policy uncertainty by including reasonable scenarios in which possible environmental policies would exist that would result in costs and benefits from compliance with the relevant laws.

The Energy Security Board is currently developing a proposed design for the National Energy Guarantee (the Guarantee), which aims at integrating long term energy and

70 See AEMC, *Progress update: Frequency control frameworks review*, 19 December 2017.

emissions policy.[71] The Guarantee is designed to provide a long term energy policy to promote energy reliability, security and affordability, whilst setting the required emissions target at a level consistent with Australia's international emissions reduction commitments.

We note that there is ongoing work being undertaken to develop the detail for the Guarantee. If the Guarantee is implemented, we will provide updated guidance on the treatment of this policy in RIT assessments.

Question 12: What additional guidance would stakeholders find useful in regarding the treatment of environmental policies in the RIT–T application guidelines?

5.7 Discount rate and treatment of risks

The RIT–D application guidelines and the RIT–T currently specify the method for determining the discount rate or rates to apply in the RITs. The general approach is that:[72]

- The discount rate in the RITs must be appropriate for the analysis of a private enterprise investment in the electricity sector and must be consistent with the cash flows that the RIT proponent is discounting.
- RIT proponents must use the regulated cost of capital as the lower bound for the discount rate.
- In the case of the RIT–D, the application guidelines add that RIT–D proponents need the flexibility to account for the different levels of risk between projects when setting discount rates.

The current non-prescriptive approach provides RIT proponents with the flexibility to adjust the discount rate to reflect the risks that different types of projects carry. A potential disadvantage of this approach is that RIT proponents could plausibly inflate the relative benefits of particular options by applying an overly inflated discount rate to other options. In doing so, a RIT proponent could change the ranking of different credible options. For example, if a RIT proponent had an intrinsic preference towards network options over non-network options; it could plausibly choose to exaggerate the risk of the non-network options in setting an inflated discount rate.

Given this potential limitation, we would like to explore stakeholder support for specifying that RIT proponents, as a default, should use the same discount rate for different credible options to address a given identified need. If a RIT proponent has a sound reason to use a different discount rate for a particular credible option, it must:

- Clearly and transparently provide this reasoning; and
- Show if or how this decision affects the ranking of credible options;

We consider there is merit in setting this default because:

71 See Energy Security Board, *Overview: Retailer reliability and emissions guarantee*, 7 November 2017.

72 AER, *RIT–D application guidelines*, September 2017, p. 20; AER, *RIT–T*, June 2010, clauses (14) and (15)(g).

- We consider there would unlikely be a material difference in the risks between different credible options to meet a given identified need on the electricity network. In particular, we consider a network business' regulated cost of capital would typically reflect the opportunity cost for the different credible options under its consideration.
- Using the same discount rate for different credible options should still allow RIT proponents to adequately account for any difference in riskiness between the different options. This is because RIT proponents would still consider how the relative costs and benefits of different credible options vary through the scenario analysis. Rather than capturing the relative riskiness through the discount rate, we could take the position that scenario analysis should, in general, adequately capture the relative risk factors of different credible options.

Question 13: Do you support our proposal to expand our RIT application guidelines to specify that, as a default, RIT proponents should use the same discount rate when comparing different credible options?

5.8 Value of customer reliability

The value of customer reliability (VCR) represents the economic harm to customers per MWh that arises from involuntary loss of supply of electricity. VCR could vary by:

- time of day;
- customer type (for example small or large industrial, restaurant, commercial, or household);
- the activity of the customer at the time; and
- location.

In network planning, the VCR is used to assess the economic merits of carrying out additional investment in the electricity network. Therefore, the application of the RITs requires that RIT proponents use a reasonable measure of the VCR in calculating market benefits. A RIT proponent should also use VCR estimates from a reputable source, such as AEMO.

In our assessment of a number of current RITs being undertaken, we have seen that the selection of an appropriate VCR is becoming of greater importance with the focus on system security.

We consider that the RIT application guidelines do not need to be overly prescriptive on the selection of an appropriate VCR, particularly as the VCR could vary project by project. However, we also consider that stakeholders and network businesses would benefit from some commentary on the selection of appropriate VCR in the RIT application guidelines.

Question 14: What kind of additional guidance, if any, would you like the RIT application guidelines to provide on selecting an appropriate VCR?

5.9 Selection of base case

In completing a cost–benefit analysis by applying the RIT application guidelines, network businesses estimate the benefits of a credible option by comparing, for each relevant reasonable scenario, the state of the world with that credible option in place with the base case. This base case is:

- In the case of the RIT–T, the state of the world in which the network business does not implement a credible option (that is, a 'business-as-usual' option).[73] This is prescribed in clause 5.16.1(c)(1) of the NER.
- In the case of the RIT–D, the state of the world in which the network business does not implement a credible option, unless the identified need is for reliability corrective action. Under the current drafting of the RIT–D application guidelines, for reliability-driven projects, the RIT–D proponent can calculate the relative market benefit of a credible option by:[74]

> *selecting one credible option to serve as the base case for the RIT–D analysis (base case credible option)*
>
> *comparing for each reasonable scenario, the state of the world with each other credible option (other credible option) in place against the state of the world with the base case credible option in place*
>
> *where the state of the world with another credible option in place exhibits benefits compared to the state of the world with the base case option in place, the difference is a relative market benefit to that other credible option. Where the reverse occurs, the difference is a negative relative market benefit or a relative market cost and*
>
> *weighting any relative market benefits or costs by the probability of each reasonable scenario occurring.*

With regards to the current drafting of the RIT–D application guidelines, it is worth noting that for repex projects, the primary market benefit of a credible option will be the present value of the reliability costs under the 'business-as-usual' base case. In light of the repex rule change, it would be worthwhile revising the RIT–D application guidelines to clarify that a RIT–D proponent should use a 'business-as-usual' base case for repex projects unless a failure to replace (or implement a substitute for) the network element being replaced would violate applicable reliability standards.

Question 15: Should we revise the RIT–D application guidelines to clarify that a 'business-as-usual' base case should be used for repex projects? Is there any other guidance the RIT application guidelines should provide on selecting an appropriate base case?

73 AER, *RIT–T application guidelines*, September 2017, p. 14.

74 AER, *RIT–D application guidelines*, September 2017, p. 35.

6 Other RIT issues — Integrated System Plan

Currently, the RIT–T application guidelines provide guidance on using AEMO's National Transmission Network Development Plan for developing assumptions to use in a RIT–T analysis. However, in accordance with the recommendations of the Finkel Review, AEMO is developing an Integrated System Plan (ISP), which would facilitate an orderly energy transition under a range of scenarios.

In the consultation paper, AEMO notes that the first ISP proposed to be released in June 2018 will aim to deliver a strategic infrastructure development plan, based on sound engineering and economics, which can facilitate an orderly energy system transition under a range of scenarios. This ISP will particularly consider:

- What makes a successful renewable energy zone (REZ) and, if REZs are identified, how to develop them.
- Transmission development options.[75]

The ISP is being developed out of one of the recommendations of the Finkel Review.[76] This recommendation was for more strategic planning of transmission infrastructure, including a new planning mechanism to facilitate the efficient development and connection of new REZs.[77] There have been examples overseas where REZ have been used as a transmission planning tool to enable the 'scale up' of solar, wind, and other resources on the grid.[78]

The Finkel Review saw the RIT–T and ISP as having an important relationship, and noted that augmentations in line with the ISP would be evaluated through the RIT–T process or its successor.[79]

Consistent with the Finkel Review recommendations and AEMO's ongoing work on the ISP, we consider that the ISP, through providing an integrated transmission and generation plan, will assist the market in making informed investment decisions.

Question 16: Given AEMO is currently developing the Integrated System Plan (ISP), what additional guidance would stakeholders find useful in the RIT–T application guidelines with respect to the ISP?

75 AEMO, *Integrated System Plan Consultation*, December 2017, p. 3.

76 The Finkel Review recommended the introduction of 'Integrate Grid Plans', which AEMO is developing under the name, 'Integrated System Plan'.

77 Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 26.

78 For examples, see Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 125.

79 Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 124.

A History and use of the RITs to date

This appendix discusses the development of the RITs, and their predecessors, 'the regulatory tests'. It provides an assessment of how it has improved over time and how effective it has been to date.

Before the regulatory investment tests

Before the creation of the NEM, state owned networks were responsible for network planning across each of the electricity supply chain segments in respective states. With the introduction of the NEM and the National Electricity Code 1998, a customer benefits test was introduced to better coordinate network planning across the NEM. The customer benefits test ensured that network investment would only be undertaken if customers benefited from that investment.

In 1999 the Australian Competition and Consumer Commission (ACCC) developed the regulatory test based on maximising net public benefits or market benefits to ensure costs were also incorporated in the test (version 1). The then ACCC Chair explained the purpose of the test as:[80]

> *The ACCC's new investment test is designed to allow the regulated networks to make new investments that are in the interests of consumers without adversely affecting the increasingly competitive National Electricity Market*

The ACCC explained the effect of the test as:[81]

> *The new test, which applies to regulated inter-connectors and system augmentations, requires National Electricity Market planners to: compare network investments with alternative options, such as co-generation and energy efficient technologies and practices; take into account the environmental requirements of the governments making up the National Electricity Market; and ensure that investments maximise net public benefits;*

We later described this as:[82]

> *In developing the regulatory test, the ACCC relied on the Code's [the National Electricity Code 1998] key principles of economic efficiency and competitive neutrality. Consequently, the ACCC based the test on the traditional cost-benefit analysis framework but with a number of qualifications to limit any adverse impacts that regulated network investments might have on the contestable parts of the industry.*

80 Professor Allan Fels, *ACCC media release: ACCC Decides - Electricity investments must deliver net public benefits*, 22 December 1999.

81 ACCC, *ACCC media release: ACCC Decides - Electricity investments must deliver net public benefits*, 22 December 1999.

82 AER, *Review of the regulatory test — Decision*, 11 August 204, p. 17

The ACCC was tasked to review the test given the former market operator and other stakeholders identified a number of concerns with this test, including consistency, definitions and competition benefits. In August 2004, the ACCC updated the test (version 2).

Following changes to the NER in 2006, we revised the regulatory test in November 2007 (version 3) to include information for alternative options. We also introduced the notion of likelihood in the consideration of alternative options.

Network businesses applied the regulatory test to assess and rank different investment options. The regulatory test was based on a cost-benefit analysis framework. It relied on the principles of economic efficiency and competitive neutrality, with a view for network businesses to consider network and non-network investments equally.

The regulatory test consisted of two limbs:

1. The reliability limb—applied to investments which are required to meet service standards obligations in the NER, state legislation, regulations or statutory instruments. A reliability augmentation will satisfy the test if it is the least cost option considering the total costs of the alternative options to those who produce, distribute and consume electricity in the NEM.
2. The market benefits limb—applied to non-reliability driven investment. New investment will satisfy the test if it maximises the net present value of the market benefits having regard to alternative options, timing and market development.

Development of the RIT–T

In 2006, the COAG established an Energy Reform Implementation Group to review the operation of Australia’s energy sector. The review found that the investment decision making criteria in the regulatory test were appropriate, but recommended amalgamating the reliability and market benefits limbs of the test.

The AEMC developed options to implement these recommendations in its national transmission planning arrangements review. As part of its review, the AEMC proposed a new framework and process for assessing transmission investment to replace the regulatory test. This framework included the development of a RIT–T, which would provide a single cost benefit analysis framework to apply to all transmission investment. The RIT–T would remove the distinction between reliability driven projects and projects motivated by the delivery of market benefits. Proposed transmission projects would be assessed against both local reliability standards and their ability to deliver benefits to the market.

In July 2009, the AEMC amended the NER to implement its proposed framework and process for assessing transmission investment. Under these amendments, transmission investment became subject to assessment under the RIT–T from 1 August 2010. The amalgamation of the reliability limb and the market benefits limb is reflected in the NER, which requires the RIT–T identify the option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the 'market'.[83]

Development of the RIT–D

When the AEMC had amended the NER to include the RIT–T, a new project assessment process for distribution, the RIT–D, had already been under consideration to replace the existing regulatory test for distribution investment. The RIT–D provisions were included in the NER on 1 January 2013, and came into effect for projects after 1 January 2014.

On 23 August 2013, we published the RIT–D and its application guidelines. Like the RIT–T, the RIT–D replaces the regulatory test and amalgamates its reliability and market benefits limbs.

The RIT-D provisions followed from the AEMC's national distribution planning arrangements review.[84] As such, it was complemented by a range of new planning measures to encourage better non-network engagement and public reporting.[85] The RIT–D itself requires distribution networks to give due consideration to non-network options. Specifically, a RIT–D proponent must publish and consult on a non-network options report unless, having screened for non-network options, it determines that no non-network option is or forms a significant part of any credible option.[86]

Including replacement expenditure

In July 2017, the AEMC made the repex rule change. Among other changes to the NER, this extended the RITs to network repex decisions. It also aligned the RIT–T with the RIT–D requirement for the proponent to reapply the test where, in the reasonable opinion of the RIT proponent, there is a material change in circumstances, unless we determine otherwise.[87] The rule included transitional arrangements requiring us to amend and publish RIT documentation to take into account the amending rule by no later than 18 September 2017.[88]

In September 2017, we made the necessary amendments to accommodate this repex rule change. This did not require amendments to the RITs themselves, but required updating the following parts of the RIT application guidelines:[89]

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83 Clause 5.16.1(b) of the NER, which relates to the RIT–T, uses the definition of market in chapter 10 of the NER. This is, 'any of the markets or exchanges described in the Rules, for so long as the market or exchange is conducted by AEMO'.

84 AEMC, *Rule determination: National electricity amendment (distribution network planning and expansion framework) rule 2012 No. 5*, October 2012.

85 AEMC, *Information sheet: More efficient distribution network planning*, 11 October 2012.

86 See AER, *RIT–D application guidelines*, September 2017, p. 10.

87 NER Clauses 5.16.4 (z3), 5.17.4 (t)

88 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

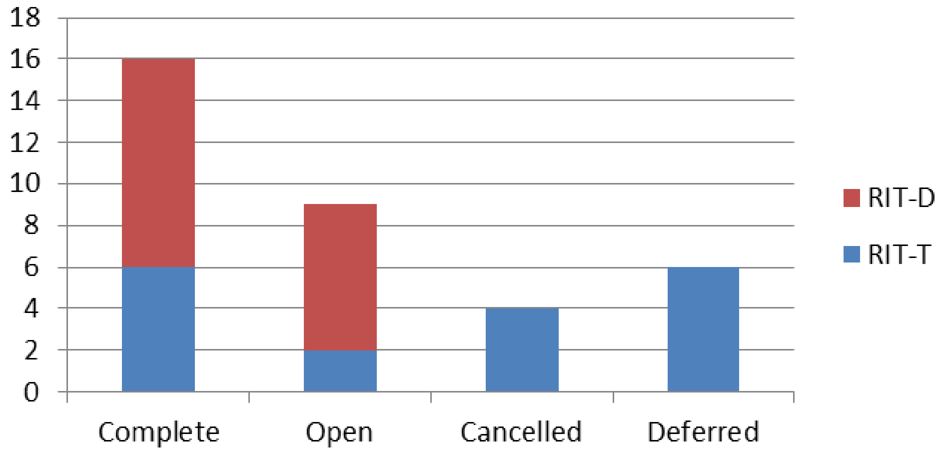
89 See AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017*, accessed 3 January 2018, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017.

- Our cost threshold references;
- NER clause references throughout the RIT-T application guideline to address the renumbering of clauses
- Removing italicised terms from the RIT-T application guideline (for consistency with the RIT-D application guideline).

Overview of the RITs to date

We have been monitoring the application of the RIT–T and RIT–D since their commencement in June 2010 and August 2013, respectively. Figure 3 summarises the number of RITs that network businesses have commenced to date.

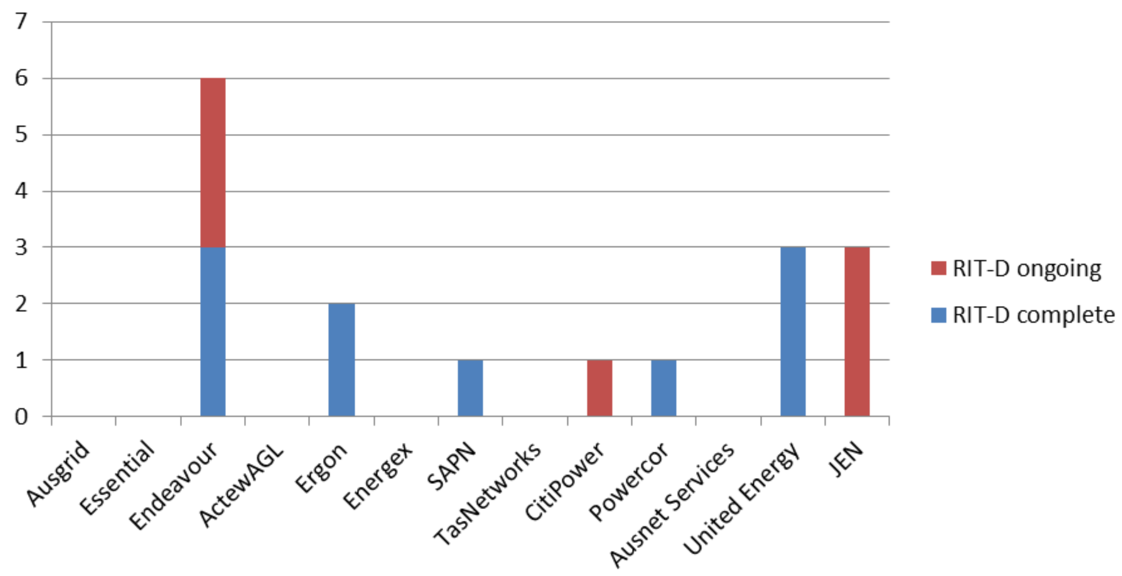
Figure 3: RITs commenced to date



The RIT–D to date

The NER have required distribution businesses to apply the RIT–D since 1 January 2014. As such, we have been monitoring the application of the RIT–D for approximately four years. Figure 4 illustrates that seven of the 13 distribution businesses have commenced a RIT–D over this time, with only five having completed a RIT–D.

Figure 4: RIT–Ds commenced to date by distribution business



Giving due consideration to non-network options is an important component of the RIT–D. A RIT–D proponent must publish and consult on a non-network options report unless, having screened for non-network options, it determines that no non-network option is or forms a significant part of any credible option.[90] Of the 17 applications of the RIT–D to date, 11 published non-network options reports. Of these non-network options reports, six were published for RIT–Ds that are now complete, and one of these RIT–Ds resulted lead to a non-network option being the preferred option.

Table 4 summarises data on the 10 RIT–Ds that distribution businesses have completed to date. So far, on average, the RIT–D process has taken approximately a year to run. On average, distribution networks have finalised their RIT–Ds approximately two years before their anticipated project commissioning date.

Table 4: Selected summary data on completed RIT–Ds

Project	RIT–D period (months)*	Approximate period from RIT–D to project start (months)**	Estimated forecast cost of preferred option ($m)	Non-network options assessed
Endeavour: Catherine Fields (Part 1) Precinct	12	26	15.8	No non-network options report
Endeavour: North Box Hill zone substation	11	40	8	No non-network options report
Endeavour: North Leppington and Leppington Precincts	13	28	24	No non-network options report

90 See AER, *RIT–D application guidelines*, September 2017, p. 10.

Ergon: Emerald 66kV Network	17	31	3.57	Yes, one proposal on non-network options report
Ergon: Network limitations in the Charlton/ Wellcamp area	5	21	7.72	No non-network options report
Powercor: Melton and Bacchus Marsh	18	10	7.8	Yes, one proposal on non-network options report
SAPN: Kangaroo Island	8	12	25.6	Yes, eight proposals on non-network options report
United Energy: Dromana supply area	7	24	8.4	Yes, United Energy received several submissions on its non-network options report
United Energy: Lower Mornington Peninsula area	19	29	35	Yes, and forms part of preferred option
United Energy: Notting Hill Supply Area	8	12	5.9	Yes, one proposals on non-network options report
Average	**12**	**23**	**14**	

* Measured from the publication of the non-network options report or equivalent document to the publication of the final project assessment report.

** Measured from the publication of the final project assessment report to the estimated commissioning date of the preferred option in the final project assessment report or distribution annual planning report.

Table 5 provides a summary of the RIT–Ds we have been monitoring to date.

Table 5: Previous applications of the RIT–D

Proponent	Project	Status	Description	Non-network options
CitiPower	North Richmond zone substation	**Open**. Published a no non-network options notice in 12/2014. Since the preferred network option is less than $10m, CitiPower does	Estimated capital cost: $5m+ Identified need: Forecast 11 kV fault levels at North Richmond zone substation will exceed the Victorian Electricity Distribution Code limit. Likely preferred option: Install fault limiting reactors at North	Published a no non-network options notice in 12/2014.

		not intend to publish a draft project assessment report. As the preferred option is less than $20 m, CitiPower will publish its final project assessment report as part of its Distribution Annual Planning Report.	Richmond to keep within the 18.4 kA rating for equipment.	
Endeavour Energy	Catherine Fields (Part) Precinct	**Complete**. Final report published 10/2017	Estimated cost of preferred option: $15.8m with zone substation, $5.1m without the zone substation. Identified need: Addressing a network limitation resulting from the development in the Catherine Fields precinct. The strong growth in demand results in load at risk from 2019 by exceeding the 11kV feeder design capacity. Preferred option: Extend three 11kV feeders from Oran Park Zone Substation as a first stage. Build 132/11kV zone substation as a second stage.	Screening for non-network options report on 24/10/2016. Found a demand reduction potential of 1.0 MVA on the 11kV network supplying the Catherine Fields Precinct, which falls short of the required demand reduction of 4.5 MVA for a one year deferral and 8.3 MVA for a two year deferral.
Endeavour Energy	Marayong ZS Renewal Project	**Open**. 11/10/2017 non-network options report published. Submissions closed 12/1/2018.	Estimated cost of the network option: $19m Identified need: Renewal of the Marayong substation ensure its safe and reliable operation, as it nears the end of its serviceable life.	Non-network options report ongoing consultation.
Endeavour Energy	North Box Hill zone substation	**Complete**. Final report published 3/2016. Endeavour did not publish the draft report as the preferred option is less than	Estimated capital cost: $8m Identified need: Address forecast increased load, which will exceed feeder capacity. Preferred option: Extend 2x 22kV feeders from the	Notice of no viable network options published 4/2015. Found demand management could only reduce demand supplied by the Riverstone

		$10m.	Mungerie Park Zone substation and convert the 11kV network into 22kV	zone substation by 238 kVA per year, which is short of the 1920 kVA demand reduction needed.
Endeavour Energy	North Leppington and Leppington Precincts	**Complete**. Final project assessment report published in 4/2017.	Estimated project cost is $24m. Identified need: A new zone substation is required to service an ongoing development. Preferred option: Establish a two transformer zone substation with a standard control building at North Leppington.	In 2/2016, Endeavour published a screening for non-network options report concluding that the amount of demand reduction feasible fell short was what was required to achieve a one year deferral.
Endeavour Energy	South Marsden Park Zone Substation RIT-D	**Open**. Draft project assessment report published January 2018.	Estimated cost of indicative preferred option: $24.6m Identified need: The South Marsden Park ZS to experience load at risk and unserved energy from summer 2018/19.	No submissions received on its non-network options report.
Ergon Energy	Emerald 66kV Network	**Complete**. Published final report on 30/11/2016.	Estimated cost of preferred option: $3.57m. Identified need: Addressing emerging capacity constraints in the Emerald area so the 66kV have sufficient capacity to supply peak load and to prevent voltage constraints Preferred option: 11MWAr of compensation and Blackwater Line Upgrade.	A non-network options report was published on 1/72015. One submission proposed an embedded diesel power station, which Ergon included as a component of one of the credible options considered in the project assessment draft report.
Ergon Energy	Network limitations in the Charlton/ Wellcamp	**Complete**. Final report published 16/9/15. Ergon did not publish a draft project	Estimated capital cost: $5.72m Identified need: Addressing increasing load from	Determined that no viable non-network options exist.

	area	assessment report as the cost of the preferred option was less than $10m	increased customer connections that will likely cause voltage and capacity constraints. Preferred option: Install a 33/11kV, 10MVA Skid Substation in Charlton	
Jemena Electricity Networks	Flemington Electricity Supply	**Open**. Draft Project Assessment Report published on 16/12/2016. Consultations closed on 31/1/2017	Estimated capital cost: $10.4-$15.9m Identified need: Addressing insufficient thermal capacity in Flemington zone substation to supply forecast load, which is exacerbated by limited transfer capability given high levels of feeder utilisation and limited available support from the Essendon and North Essendon zone substations.	Non- network options report received 2 submissions presenting credible-non-network options—a voluntary load reduction and a battery energy storage solution. Jemena's analysis found that neither of these would defer the need for the preferred network augmentation.
Jemena Electricity Networks	Keilor - Tullamarine - Airport West - Pascoe Vale 66kV sub-transmission loop capacity constraint	**Open**. Draft Project Assessment Report published on 5/7/2017.	Estimated cost of indicative preferred option: $11.16m. Identified need: Increasing network capacity to meet increasing demand.	Determined that no viable non-network options exist.
Jemena Electricity Networks	Sunbury – Diggers Rest Electricity Supply	**Open**. Draft Project Assessment Report published on 25/1/2017. Submissions close on 10/3/2017.	Estimated capital cost: $10.2-25.7m Identified need: Extend capacity of Sunbury Zone substation given higher forecast demand over the next two years in the Sunbury and Diggers Rest areas.	Non-network options report received 2 submissions presenting credible-non-network options—a voluntary load reduction and a battery energy storage solution. Jemena's analysis found that neither of these would

				defer the need for the preferred network augmentation.
Powercor	Melton and Bacchus Marsh	**Complete**. Final report published 6/9/2016.	Estimated total direct capital cost of the preferred option: $7.8m Identified need: Due to forecast increases in demand, the Melton and Baccus Marsh zone substations are approaching their N ratings. The Brooklyn terminal station to Baccus Marsh 66 kV sub-transmission line is forecast to be above its N rating in summer 2016/17. Preferred option: Install a third transformer in the Melton zone substation and construct a new 22kV feeder to transfer 5 MW of load from Baccus Marsh customers to Melton.	Non- network options report received one formal submission, but the proponent withdrew its original proposal as it became no longer economically viable to address the identified need.
SA Power Networks (SAPN)	Kangaroo Island: RIT–D and dispute	**Completed** RIT–D. Final Project Assessment Report Published 23/12/ 2016 Completed dispute. Notice received on 23/01/2017, determination made on 17/5/2017.	Estimated capital cost: $45m Identified need: The radial 33kV submarine cable to Kangaroo Island is nearing its design life expectancy of 30 years with significant consequences if the cable fails. Preferred option: installing a new 33kV submarine cable by 2018 Dispute: The Kangaroo Island Council disputed that a larger capacity cable would provide benefits in regards to the option value and reduction in losses, which SAPN did not account for sufficiently. Decision on dispute: We did not require SAPN to amend its final report. While SAPN's	Non- network options report received 8 submissions ranging from a combination of proven technologies such as biomass, bio-diesel, solar and wind generation, battery storage to unproven concepts, technologies and consultancy offers. SAPN identified three technically credible non-network options, which it assessed in detail.

			assessment did not properly account for 'option value', including a 'high demand' scenario, this would not change the outcome of the RIT-D assessment.	
United Energy	Dromana supply area	**Completed** RIT–D. Final Project Assessment Report published 9/2015	Estimated cost of preferred option: $8.4m (PV) Identified need: Addressing load at risk Preferred option: Install transformer, extend indoor bus, upgrade protection and control schemes. Develop 2 distribution feeders	Received several submissions on its non-network options report.
United Energy	Lower Mornington Peninsula area	**Complete**. Final report published 25 May 2016.	Estimated cost of preferred option: $35m Identified need: Meeting maximum demand so that five 66KV lines do not exceed their N-1 thermal ratings. Maintaining voltage levels within regulatory limits in the event of an outage of either the Mornington to Dromana 66 kV line or the Tyabb terminal station to 66 kV line at maximum demand conditions, Preferred option: Contracting with Greensync for demand reduction non-network support services and implementation of a network solution beginning December 2018.	Non- network options report received two technically credible non-network options. One of these proposals formed part of the preferred option.
United Energy	Notting Hill Supply Area	**Complete**. Final project assessment report published 12/2016.	Estimated capital cost of preferred option: $5.07m. Identified need: Energy at risk should a forced transformer outage occur, given forecast demand growth in the next five years. Preferred option: Install a third transformer at Notting Hill zone substation and two	Notice of no viable non-network options - published 8/4/2016.

	new Distribution Feeders by December 2017

The RIT–T to date

We have been monitoring the application of the RIT–T since it has applied to transmission networks in August 2010. As Figure 5 shows, there have been 18 applications of the RIT–T to date, with several of these applications becoming cancelled or deferred.

Figure 5: RIT–Ts commenced to date by RIT–T proponents

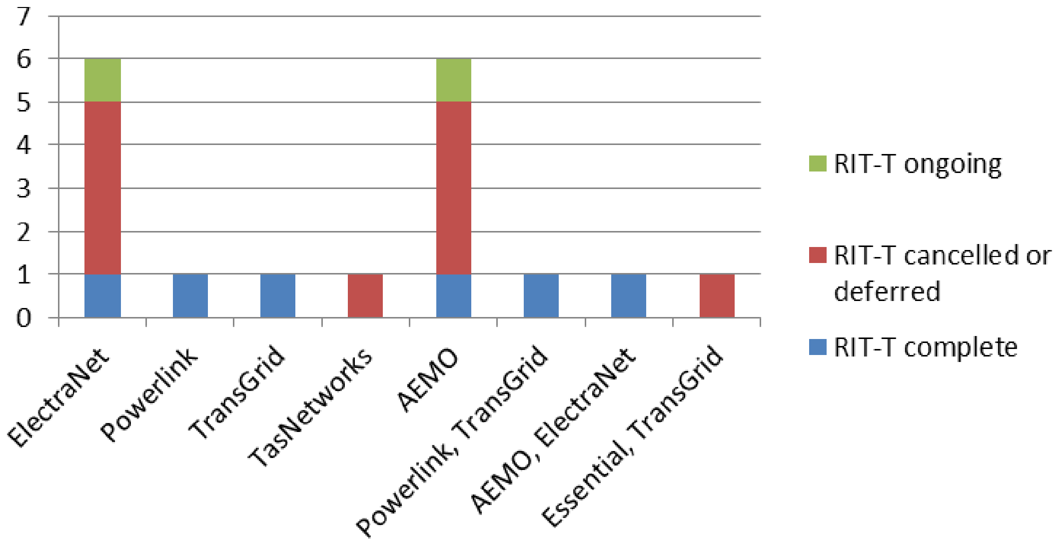


Table 6 summarises selected data on the six RIT–Ts that transmission businesses have completed to date. So far, on average, the RIT–T process has taken approximately 1.5 years to run. On average, transmissions networks have finalised their RIT–Ts approximately 2.5 years before their anticipated project commissioning date.

Table 6: Selected summary data on completed RIT–Ts

Project	RIT–T period (months)*	Approximate period from RIT–T to project start (months)**	Estimated forecast cost of preferred option ($m)
AEMO: Regional Victoria Thermal Capacity – Ballarat and Bendigo Supply	18	21	126.2
AEMO: ElectraNet Heywood interconnector	21	36	107.7
ElectraNet: Dalrymple substation upgrade	7	36	26.8
Powerlink: Maintaining a reliable electricity supply to the Bowen	14	5	23.8

Basin coal mining area			
Powerlink, TransGrid: Development of the Queensland – NSW interconnector	29	N/A (do-nothing option selected)	0
TransGrid: Powering Sydney's Future	13	56	377
Average	17	31	110.3

* Measured from the publication of the project screening consultation report or equivalent document to the publication of the project assessment conclusions report.

** Measured from the publication of the project assessment conclusions report to the estimated commissioning date of the preferred option.

Table 7 provides more detail on these applications of the RIT–T.

Table 7: Previous applications of the RIT–T

Proponent	Project	Status	Description
AEMO	Eastern Metropolitan Melbourne Reactive Support	**Cancelled** on 6/2/2013 due to the revised forecast in electricity use, after consultation report on 22/112011.	Estimated project cost: $8.1-9.1m. Identified need: Additional reactive support in the Cranbourne or Rowville area by summer 2014-15 to maintain stable voltage following unplanned network outages.
AEMO	Eastern Metropolitan Melbourne thermal capacity upgrade	**Deferred** given revised forecast in electricity use. Deferred after draft report on 8/3/2013.	Estimated project cost: $40-182m. Identified need: Preventing loading transmission elements beyond their thermal capability due to continual demand growth in the Eastern Metropolitan Melbourne area.
AEMO	Regional Victoria Reactive Support RIT-T	**Deferred** following revised forecasts. Delay announced after consultation repot on 30/1/2012	Estimated project cost: $5-10m. Identified need: Additional reactive support in Regional Victoria to ensure that stable voltage control is maintained following unplanned network outages. The network option that AEMO considered consisted of various combinations of capacitor banks at Bendigo Terminal Station.
AEMO	Regional Victoria Thermal Capacity – Ballarat and Bendigo Supply	**Completed** project assessment conclusions report in10/10/2013. Ongoing project	Estimated cost of preferred option: $126.2m (PV). Identified need: Supply security for customers in the north-west of Victoria at risk due to potential overload on the existing Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line Preferred option: 3 stage solution. First, install a

		updates. Update June 2014: AEMO ran a tender process seeking firm quotes from non-network service providers and AusNet. Update May 2015: AEMO will likely defer the final stage of this project	wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2015–16. Then, string a new line on the vacant side of the existing towers on the Moorabool–Ballarat No.2 220 kV line in 2017–18. Thirdly, replace the towers to up-rate the existing Ballarat–Bendigo 220 kV line to a maximum operating temperature of 82 ºC in 2019–20.
AEMO	Victorian Reliability Support	**Deferred** due to a reduction in the maximum demand forecast. Deferred after the Project Assessment Conclusions Report published 3/5/2012	Estimated project cost: $ 5- 7.24m. Identified need: Increasing the thermal capability of the Murray- Dederang 330 kV lines of approximately 300 MW at peak demand times for market benefits (by increasing imports from NSW to Victoria) Preferred option: tender for demand side response option to voluntarily curtail load at a cost less than the cost of involuntary load reduction.
AEMO	Western Victoria Renewable Integration	**Open**. Project screening consultation report published 4/2017.	Estimated project cost:$3.0 (lower bound of minor augmentations) –$1,650 (upper bound of 500 kV augmentation) Identified need: Increasing the capability of the Western Victoria power system, to reduce constraints on projected new generation in that region.
AEMO, ElectraNet	Heywood interconnector	**Complete**. Published conclusions report on 9/1/ 2013. On 4/9/12, the AER confirmed the preferred option satisfied the RIT-T. AEMO awarded the contract to SP AusNet in 2014.	Estimated project cost: $107.7m. Identified need: Increase VIC-SA interconnector (Heywood) capacity to increase net benefits in the NEM. Preferred option: install a third 500/275kV transformer at Heywood with additional series compensation of the South East Bend to Taliem Bend 275kV lines.

ElectraNet	Baroota substation upgrade	**Cancelled**, highlighted in project assessment draft report on 15/05/2014	Estimated capital cost: $6m. Identified need: To meet ESCOSA's revised the electricity transmission code for the Baroota connection point from reliability category 1 to category 2. Since all credible options considered had a negative NPV across a majority of the reasonable scenarios considered, ElectraNet wrote to ESCOSA to remove the N-1 category 2 reliability standard from the Baroota connection point.
ElectraNet	Dalrymple substation upgrade	**Complete**. Project assessment conclusions report issued in November 2013.	Estimated capital cost of preferred option: $26.8m (in 2013/14 dollars). Identified need: Reliability corrective action following an amendment to the SA electricity transmission code to reclassify the Dalrymple connection point from reliability category 1 to category 2. Preferred option: Extending the Dalrymple connection point and installing a second 132/33 kV transformer.
ElectraNet	Lower Eyre Peninsula Reinforcement	**Deferred** in the Project Draft Assessment Report in 9/1/2013. ElectraNet's subsequent APRs noted that the timing of the project is ultimately dependent on the timing of spot load entry.	Estimated cost: $635 –910m. Identified need: Meeting the SA Electricity Transmission Code reliability standards at Port Lincoln from2013/14. Meeting forecast load throughout the Lower Eyre Peninsula. Deferred due to reduced underlying demand growth and uncertainty in load developments. ElectraNet will delay the finalisation of the RIT-T until anticipated spot load developments become committed or prior to reliability constraints needing to be addressed.
ElectraNet	Managing voltage limitations in the Mid North of SA	**Deferred** to 2024 due to lower demand forecast. Delay announced 7/11/2012, after consultation repot on 14/08/2012	Estimated project cost: $4.9-9.4m. Identified need: Future voltage limitations at Bungama, Port Prie and Baroota connection points following an outage of the existing 200 MVA 275/132 kV transformer at Bungama. In addition, post-contingent inadequate reactive power margins at Bungama and Port Pirie.
ElectraNet	Northern South Australia Region	**Cancelled** on 4/11/2016, after project specification	Estimated capital cost: $30-100m. Identified need: Addressing potential network adequacy and security limitations to meet its

	Voltage Control	consultation report published 3/8/2016.	reliability obligations under the Electricity transmission code. These result from the retirement of the Northern power station.
ElectraNet	South Australia Energy Transformation RIT-T	**Open**. Project specification consultation report published 7/11/2016.	Estimated capital cost: $500-$2,500m. Identified need: Energy security limitations resulting from the lack of synchronous generation and intermittency of renewables.
Powerlink	Maintaining a reliable electricity supply to the Bowen Basin coal mining area	**Complete**. Project assessment conclusions report issued 5/7/2013.	Estimated capital cost of preferred option: $12.3m plus network support services costs of $11.5m ($2011/12). Identified need: Thermal limitations given strong forecast demand in the Bowen Basin coal mining area. Powerlink has obtained approval to vary the usual 'N-1' standard for supply to be this area based on incorporating the VCR, allowing for deferral of the network investment to summer 2016/17. Preferred option: Install two 132kV capacitors at Dysart Substation and one 132kV capacitor at both the Moranbah and Newlands substations by summer 2013/14; and network support services between 2014 and 2016.
Powerlink, TransGrid	Development of the Queensland – NSW interconnector RIT-T	**Complete**, do nothing. Project assessment conclusions report issued 11/2014.	Preferred option is doing nothing. Estimated project costs of other credible options were $3-2,300m. Identified need: Upgrading the transfer capacity of the Queensland-NSW interconnector to increase net economic benefits.
Essential Energy, TransGrid	Development of Electricity Supply to the Gunnedah / Narrabri / Moree Area	**Deferred** after consultation report on 1 March 2011	Estimated project cost: $36m. Identified need: Increasing capacity of the existing network supplying the Gunnedah, Narrabri and Moree area as it is presently exceeded under contingency conditions. The limitation is the summer day rating of the 969 Tamworth-Gunnedah 132 kV line.
TasNetworks (Transend)	Electricity Supply Augmentation to the Kingston Area	**Cancelled** after publishing consultation report on 28/9/2011	Estimated project cost: $19m. Identified need: Augment supply to the Kingston area from winter 2017. Preferred option: Establishing an additional 110 kV line to the Kingston area from Creek Road Substation, Hobart.
TransGrid	Powering Sydney's	**Complete**. Project	Estimated capital cost of preferred option: $377m. Identified need: Meeting reliability obligations

	Future - RIT-T TransGrid	assessment conclusions report published 11/2017.	under the Electricity transmission code given parts of the transmission and distribution networks supplying electricity to the Inner Sydney are approaching end of the their serviceable lives. Preferred option: Non-network support initially and then a deferred installation of two 330 kV cables in stages, decommissioning of Ausgrid cables in two stages and operating Cable 41 at 132 kV.